



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

January 31, 2012

Darrell Nitschke
Executive Secretary
North Dakota Public Service Commission,
State Capitol
600 East Boulevard
Bismarck, ND 58505-0480

Re: February 2012 Fuel Cost Charge

Dear Mr. Nitschke:

Northern States Power Company, a Minnesota corporation operating in North Dakota hereby submits its electric fuel cost charge (“FCC”) for February 2012.

Pursuant to the Commission authorization of the final compliance tariffs in the Company’s 2007 rate proceeding (Case No. PU-07-776) to implement new rates beginning March 1, 2009, a “multi-class” fuel cost mechanism replaced the previous single-factor mechanism. The February 2012 system FCC is based on the average of the most recent four-month actual fuel cost plus a “true-up” factor, reflecting cost recovery deviations during the December 2011 calendar month.

The table below shows the Fuel Cost Charge by customer class category:

February 2012	Fuel Cost Charge (\$/kWh)
Residential	0.02574
C & I Non-Demand	0.02727
C & I Demand	0.02642
C & I Demand Time of Day On-Peak	0.03396
C & I Demand Time of Day Off-Peak	0.01997
Outdoor Lighting	0.01832

MISO CHARGES IMPLEMENTATION

MISO Day 2 Charges

This filing includes our reporting of the Midwest Independent Transmission System Operator, Inc. (“MISO”) charges under the Day 2 Market. Pursuant to the Commission’s Order (Docket No. PU-05-147) dated April 6, 2005 and the Order in Docket No. PU-07-776, Xcel Energy is authorized to recover MISO Day 2 costs. The March 2009 FCC reflected the new MISO Day 2 charge types: 3 Auction Revenue Rights (“ARR”) and 3 new Financial Transmission Rights (“FTR”) charge types¹, to be reflected in the Fuel Cost Rider. Consistent with this Order and the required “net” accounting of Day 2 costs and revenues, we have included in the February 2012 FCC, the net MISO Day 2 costs for December 2011 as recorded in Account 555. The MISO Day 2 cost recovery included in this February FCC is \$16,321,281.92, which is the net of many items. Pursuant to the above mentioned Orders, the Company also provides more detailed records in Attachment 2, page 1 to support the calculation of the MISO Day 2 costs.

MISO ASM Charges

¹ Previously embedded in other FTR charge types.

With the implementation of the MISO Ancillary Services Market (“ASM”) on January 6, 2009, the net costs or revenues of 14 new ASM charge types are included in the Fuel Cost Rider, pursuant to the Commission guidance in Docket No. PU-09-016. Consistent with the MISO order and the required “net” accounting of ASM costs and revenues, we include in the February FCC, the net MISO ASM costs for December 2011 as recorded in Account 555. The MISO ASM cost recovery included in this February FCC is \$1,795,071, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

REFUNDS

Pursuant to the above referenced Order Adopting Settlement, the December 2011 Asset Based Margin amount of \$42,867 has been included in the February 2012 Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. Starting from February 2011, the 2010 retail share of the Non-Asset Based Margins will be credited to the monthly FCC over the following 12-month period only if the calendar year balance is positive. The realized North Dakota retail share of 2011 Non-Asset Based Margin credit is \$141,551 and this credit amount will be distributed equally each month over the following 12-month period. The refund reflected in the February FCC is \$9,247, or 0.004¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

OTHER REPORTING ITEM

Attached is the calculation of the February 2012 FCC, as well as a statistical summary of energy sources and costs, compared to the previous month.

If you have any questions regarding the information contained in this filing, please contact Dave Sederquist in Fargo at 701-241-8632.

Sincerely,

/ S /

Phillip J. Zins
Manager, Pricing and Planning
Enclosures (2)
CC: David H. Sederquist

Northern States Power Company, A Minnesota Corporation
 Electric Operations - State of North Dakota
 Derivation of Adjustment for Fuel Clause Rider
 Current Period Cost of Energy for Feb-2012

Feb-2012 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02619	-\$0.00009	-\$0.00025	\$0.02585
Residential	\$0.02607	-\$0.00009	-\$0.00025	\$0.02574
C & I Non-Demand	\$0.02763	-\$0.00010	-\$0.00026	\$0.02727
C & I Demand Non-TOD	\$0.02676	-\$0.00009	-\$0.00025	\$0.02642
C & I Demand TOD On-Peak	\$0.03440	-\$0.00012	-\$0.00033	\$0.03396
C & I Demand TOD Off-Peak	\$0.02023	-\$0.00007	-\$0.00019	\$0.01997
Outdoor Lighting	\$0.01856	-\$0.00006	-\$0.00018	\$0.01832
Residential				
Residential Service	\$ 0.02607	\$ (0.00009)	\$ (0.00025)	\$ 0.02574
Residential TOD	\$ 0.02607	\$ (0.00009)	\$ (0.00025)	\$ 0.02574
Residential - Underground	\$ 0.02607	\$ (0.00009)	\$ (0.00025)	\$ 0.02574
Residential TOD - Underground	\$ 0.02607	\$ (0.00009)	\$ (0.00025)	\$ 0.02574
Energy Control - (Non-Demand)	\$ 0.02607	\$ (0.00009)	\$ (0.00025)	\$ 0.02574
Limit Off Peak	\$ 0.02607	\$ (0.00009)	\$ (0.00025)	\$ 0.02574
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02763	\$ (0.00010)	\$ (0.00026)	\$ 0.02727
Limit Off Peak	\$ 0.02763	\$ (0.00010)	\$ (0.00026)	\$ 0.02727
Small General Service	\$ 0.02763	\$ (0.00010)	\$ (0.00026)	\$ 0.02727
Small General TOD - Metered	\$ 0.02763	\$ (0.00010)	\$ (0.00026)	\$ 0.02727
Small General TOD - Unmetered	\$ 0.02763	\$ (0.00010)	\$ (0.00026)	\$ 0.02727
Fire and Civil Defense Siren	\$ 0.02763	\$ (0.00010)	\$ (0.00026)	\$ 0.02727
Direct Current (Closed)	\$ 0.02763	\$ (0.00010)	\$ (0.00026)	\$ 0.02727
C & I Demand				
General Service	\$ 0.02676	\$ (0.00009)	\$ (0.00025)	\$ 0.02642
General TOD - On Peak	\$ 0.03440	\$ (0.00012)	\$ (0.00033)	\$ 0.03396
General TOD - Off Peak	\$ 0.02023	\$ (0.00007)	\$ (0.00019)	\$ 0.01997
Peak Controlled (Closed)	\$ 0.02676	\$ (0.00009)	\$ (0.00025)	\$ 0.02642
Peak Controlled TOD (Closed) - On Peak	\$ 0.03440	\$ (0.00012)	\$ (0.00033)	\$ 0.03396
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02023	\$ (0.00007)	\$ (0.00019)	\$ 0.01997
Peak Controlled Tiered	\$ 0.02676	\$ (0.00009)	\$ (0.00025)	\$ 0.02642
Peak Controlled Tiered TOD - On Peak	\$ 0.03440	\$ (0.00012)	\$ (0.00033)	\$ 0.03396
Peak Controlled Tiered TOD - Off Peak	\$ 0.02023	\$ (0.00007)	\$ (0.00019)	\$ 0.01997
Energy Controlled (Closed)	\$ 0.02676	\$ (0.00009)	\$ (0.00025)	\$ 0.02642
Tier 1 Energy Controlled Rider	\$ 0.02676	\$ (0.00009)	\$ (0.00025)	\$ 0.02642
Real Time Pricing - Firm - On Peak	\$ 0.03440	\$ (0.00012)	\$ (0.00033)	\$ 0.03396
Real Time Pricing - Firm - Off Peak	\$ 0.02023	\$ (0.00007)	\$ (0.00019)	\$ 0.01997
Real Time Pricing - Controllable - On Peak	\$ 0.03440	\$ (0.00012)	\$ (0.00033)	\$ 0.03396
Real Time Pricing - Controllable - Off Peak	\$ 0.02023	\$ (0.00007)	\$ (0.00019)	\$ 0.01997
Small Municipal Pumping	\$ 0.02676	\$ (0.00009)	\$ (0.00025)	\$ 0.02642
Municipal Pumping	\$ 0.02676	\$ (0.00009)	\$ (0.00025)	\$ 0.02642
Excess Energy - St. Anthony Falls	\$ 0.02676	\$ (0.00009)	\$ (0.00025)	\$ 0.02642
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01856	\$ (0.00006)	\$ (0.00018)	\$ 0.01832
Street Lighting System	\$ 0.01856	\$ (0.00006)	\$ (0.00018)	\$ 0.01832
Street Lighting Energy	\$ 0.01856	\$ (0.00006)	\$ (0.00018)	\$ 0.01832
Street Lighting Energy - Metered	\$ 0.01856	\$ (0.00006)	\$ (0.00018)	\$ 0.01832
Street Lighting Energy (Closed)	\$ 0.01856	\$ (0.00006)	\$ (0.00018)	\$ 0.01832
Street Lighting - City of St. Paul	\$ 0.01856	\$ (0.00006)	\$ (0.00018)	\$ 0.01832

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Sep-11	Oct-11	Nov-11	Dec-11	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$32,381,294	\$31,618,275	\$29,246,148	\$35,655,438	\$128,901,155
Account 518 - Nuclear Fuel	\$11,598,307	\$8,393,084	\$9,550,563	\$10,116,633	\$39,658,587
Account 555 - Purchased Power ¹	\$36,633,495	\$41,852,828	\$45,056,103	\$33,477,192	\$157,019,619
Account 555 - MISO Day 2 Charges	\$14,825,965	\$16,752,659	\$14,479,922	\$16,418,488	\$62,477,035
Account 555 MISO Day 2 - Schedule 24	(\$92,356)	(\$97,215)	(\$94,807)	(\$97,206)	(\$381,583)
Account 555 MISO - ASM Charges	\$769,417	\$2,516,975	\$1,656,473	\$1,795,071	\$6,737,936
Total MISO Charges	\$15,503,027	\$19,172,420	\$16,041,588	\$18,116,353	\$68,833,387
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$96,116,123	\$101,036,607	\$99,894,402	\$97,365,616	\$394,412,748
Less Fuel Cost of InterSystem Sales	(\$10,853,061)	(\$10,740,247)	(\$12,667,019)	(\$3,793,539)	(\$38,053,867)
Net System Costs	\$85,263,062	\$90,296,359	\$87,227,383	\$93,572,077	\$356,358,881
System MWh Sales					
Total NSP System Retail	3,719,112	3,234,963	3,063,600	3,404,903	13,422,578
Non-Gen Muni's/Load Pattern	51,583	44,858	44,747	45,419	186,607
Total NSP System MWh Sales	3,770,695	3,279,821	3,108,347	3,450,322	13,609,185
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.261¢	2.753¢	2.806¢	2.712¢	2.619¢
Base Fuel Cost Included in Rates	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢
Class Ratio/TOD Ratio					
(i) Residential	0.9956	0.9956	0.9956	0.9956	0.9956
(ii) C & I Non-Demand	1.0548	1.0548	1.0548	1.0548	1.0548
(iii) C & I Demand Non-TOD	1.0219	1.0219	1.0219	1.0219	1.0219
(iv) C & I Demand TOD On-Peak	1.3135	1.3135	1.3135	1.3135	1.3135
(v) C & I Demand TOD Off-Peak	0.7726	0.7726	0.7726	0.7726	0.7726
(vi) Outdoor Lighting	0.7088	0.7088	0.7088	0.7088	0.7088
North Dakota Fuel Cost Factor (FCF)					
				FCF Ratio	4 Month Average
(i) Residential				0.9956	2.607¢
(ii) C & I Non-Demand				1.0548	2.763¢
(iii) C & I Demand Non-TOD				1.0219	2.676¢
(iv) C & I Demand TOD On-Peak				1.3135	3.440¢
(v) C & I Demand TOD Off-Peak				0.7726	2.023¢
(vi) Outdoor Lighting				0.7088	1.856¢
North Dakota Retail MWh Sales					
(i) Residential	55,310	46,473	51,430	73,282	226,495
(ii) C & I Non-Demand	8,910	8,004	8,136	10,989	36,039
(iii) C & I Demand Non-TOD	64,666	60,842	54,756	61,589	241,853
(iv) C & I Demand TOD On-Peak	21,042	18,046	17,618	17,709	74,415
(v) C & I Demand TOD Off-Peak	30,284	27,619	28,130	29,446	115,479
(vi) Outdoor Lighting	1,386	1,541	1,761	1,989	6,677
(vii) Total	181,598	162,525	161,831	195,004	700,958
Feb-2012 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Oct-11 Balance of Unrecovered Expenses)					Total
					Oct-11
					(\$165,599)

¹ Excludes demand-related expenses

Prior Expenses Recovered in Dec-2011 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	73,282	(\$15,879)
(ii) C & I Non-Demand	10,989	(\$2,348)
(iii) C & I Demand Non-TOD	61,589	(\$12,657)
(iv) C & I Demand TOD On-Peak	17,709	(\$4,676)
(v) C & I Demand TOD Off-Peak	29,446	(\$4,743)
(vi) Outdoor Lighting	1,989	(\$290)
(vii) Total	195,004	(\$40,593)

Actual Cost Should Have Been Recovered in Dec-11				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.712¢	0.000¢	195,004	\$5,288,508

Cost Recovered in Dec-11 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	73,282	\$1,954,157
(ii) C & I Non-Demand	10,989	\$310,955
(iii) C & I Demand Non-TOD	61,589	\$1,689,918
(iv) C & I Demand TOD On-Peak	17,709	\$623,932
(v) C & I Demand TOD Off-Peak	29,446	\$610,185
(vi) Outdoor Lighting	1,989	\$37,732
(vii) Total	195,004	\$5,226,879

Total Balance of Unrecovered Expenses (Feb-12 Balance of Unrecovered Expenses)	
Feb-2012 Recovery Provision	(\$63,377)
4 Month ND Retail Total MWh Sales	700,958
Feb-2012 Recovery Provision per KWH	-0.009¢

Feb-2012 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9956	-0.009¢	-0.009¢
(ii) C & I Non-Demand	1.0548	-0.009¢	-0.010¢
(iii) C & I Demand Non-TOD	1.0219	-0.009¢	-0.009¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.009¢	-0.012¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.009¢	-0.007¢
(vi) Outdoor Lighting	0.7088	-0.009¢	-0.006¢

Feb-2012 Margin Sharing Refunds			
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	(\$42,867)	(\$9,247)	(\$52,114)
(i) Residential	-0.020¢	-0.004¢	-0.025¢
(ii) C & I Non-Demand	-0.022¢	-0.005¢	-0.026¢
(iii) C & I Demand Non-TOD	-0.021¢	-0.005¢	-0.025¢
(iv) C & I Demand TOD On-Peak	-0.027¢	-0.006¢	-0.033¢
(v) C & I Demand TOD Off-Peak	-0.016¢	-0.003¢	-0.019¢
(vi) Outdoor Lighting	-0.014¢	-0.003¢	-0.018¢

Feb-2012 Factors	
	Total
(i) Residential	2.574¢
(ii) C & I Non-Demand	2.727¢
(iii) C & I Demand Non-TOD	2.642¢
(iv) C & I Demand TOD On-Peak	3.396¢
(v) C & I Demand TOD Off-Peak	1.997¢
(vi) Outdoor Lighting	1.832¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Jan-12	Feb-12	Differ- ence	Percent Change	FCA Application Jan-12	Feb-12	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$142.7	\$128.9	(\$13.8)	-9.7%	34.1%	32.7%	-1.4%
2 Nuclear	\$41.2	\$39.7	(\$1.5)	-3.7%	9.8%	10.1%	0.3%
3 Purchases	\$164.8	\$157.0	(\$7.8)	-4.7%	39.3%	39.8%	0.5%
MISO related Purchases	\$70.4	\$68.8	(\$1.5)	-2.2%	16.8%	17.5%	0.7%
4 Total System Costs	419.0	394.4	(\$24.6)	-5.9%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$48.1	\$38.1	(\$10.1)	-20.9%	11.5%	9.6%	-1.9%
6 Net System Costs	\$370.9	\$356.4	(\$14.5)	-3.9%	88.5%	90.4%	1.9%
7							
8 ** GWH OUTPUT **							
9 Fossil	5,091	4,723	(368)	-7.2%	31.8%	26.4%	-5.4%
10 Nuclear	4,333	4,265	(68)	-1.6%	27.1%	23.9%	-3.2%
11 Purchases	5,032	4,950	(82)	-1.6%	31.5%	27.7%	-3.8%
12 Hydro & Other	874	752	(122)	-14.0%	5.5%	4.2%	-1.3%
13 Net Interchange	658	3,178	2,520	383.0%	4.1%	17.8%	13.7%
14 Total Output	15,988	17,868	1,880	11.8%	100.0%	100.0%	0.0%
15 Intersystem Sales	894	868	(26)	-2.9%	5.6%	4.9%	-0.7%
16 Native Requirement	15,094	17,000	1,906	12.6%	94.4%	95.1%	0.7%
17							
18 ** COST per KWH OUTPUT (\$) **							
19 Fossil	2.803	2.729	-0.074	-2.6%			
20 Nuclear	0.950	0.930	-0.020	-2.1%			
21 Purchases	3.275	3.172	-0.103	-3.1%			
22 Total System Costs	2.621	2.207	-0.414	-15.8%			
23 Intersystem Sales	5.383	4.383	-1.000	-18.6%			
24 Net System Costs	2.457	2.096	-0.361	-14.7%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,591	13,609	(982)	-6.7%			
28							
29 COST per KWH SALES (\$)	2.542	2.619	0.077	3.0%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.015	-0.009	0.006				
(i) Residential	-0.015	-0.009	0.006				
(ii) C & I Non-Demand	-0.016	-0.010	0.007				
(iii) C & I Demand Non-TOD	-0.016	-0.009	0.007				
(iv) C & I Demand TOD On-Peak	-0.020	-0.012	0.008				
(v) C & I Demand TOD Off-Peak	-0.012	-0.007	0.005				
(vi) Outdoor Lighting	-0.011	-0.006	0.005				
32 REFUND	-0.016	-0.024	-0.008				
(i) Residential	-0.016	-0.025					
(ii) C & I Non-Demand	-0.017	-0.026					
(iii) C & I Demand Non-TOD	-0.016	-0.025					
(iv) C & I Demand TOD On-Peak	-0.021	-0.033					
(v) C & I Demand TOD Off-Peak	-0.012	-0.019					
(vi) Outdoor Lighting	-0.011	-0.018					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.511	2.586	0.075	3.0%			
(i) Residential	2.499	2.574	0.075				
(ii) C & I Non-Demand	2.648	2.727					
(iii) C & I Demand Non-TOD	2.565	2.642					
(iv) C & I Demand TOD On-Peak	3.297	3.396					
(v) C & I Demand TOD Off-Peak	1.939	1.997					
(vi) Outdoor Lighting	1.779	1.832					

Residential BILL IMPACT (\$'s)

Calculations:

[4] = [1]+[2]+[3]	[21] = [3] / [11]
[6] = [4] - [5]	[22] = [4] / [14]
[14] = [9]+...+[13]	[23] = [5] / [15]
[16] = [14] - [15]	[24] = [6] / [16]
[19] = [1] / [9]	[29] = [6] / [27]
[20] = [2] / [10]	[33] = [29]+[31]

KWh	Change from Previous Month
100	\$0.07
250	\$0.19
500	\$0.37
750	\$0.56
1,000	\$0.75

Some miscellaneous totals refer to so many terms that their formula would be too long. So intermediate totals are developed here, then an overall total is taken and is rounded, and finally it's simply referred to above.

	<u>FCA Application</u>	
	Jan-12	Feb-12
** GWH OUTPUT **		
Thermal	477,245	366,324
Disper gen	(90)	(90)
Hydro plus Wind	397,213	386,150
Hydro and Other	874,368	752,384
Rounded to nearest thousand:	874	752
Sales		
Non Gen Munic Total	194,126,000	186,607,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	894,119,000	868,151,000
Rounded to nearest million:	894.119	868.151

		System	Intersystem	Retail
December 2011 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 19,631,394.37	\$ 1,646,545.12	\$ 21,277,939.49
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,654,251.80	\$ -	\$ 2,654,251.80
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (10,132,544.80)	\$ -	\$ (10,132,544.80)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 585,924.94	\$ -	\$ 585,924.94
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	\$ 730,235.42	\$ 692,419.30	\$ 1,422,654.72
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (19,290.29)	\$ -	\$ (19,290.29)
14	Real-Time Distribution of Losses Amount	\$ (1,051,327.46)	\$ -	\$ (1,051,327.46)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (87,661.28)	\$ -	\$ (87,661.28)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 23,717.34	\$ -	\$ 23,717.34
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 635.69	\$ -	\$ 635.69
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 2,758,222.84	\$ -	\$ 2,758,222.84
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 789,309.10	\$ -	\$ 789,309.10
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	\$ 84,930.43	\$ -	\$ 84,930.43
15	Real-Time Financial Bilateral Transaction Congestion Amount	\$ -	\$ -	\$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component (1)	\$ (1,976.13)	\$ -	\$ (1,976.13)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (3,577,479.52)	\$ -	\$ (3,577,479.52)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (266,957.26)	\$ -	\$ (266,957.26)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (3,882.43)	\$ -	\$ (3,882.43)
37	Financial Transmission Guarantee Uplift Amount	\$ 3,883.22	\$ -	\$ 3,883.22
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 1,201,930.28	\$ -	\$ 1,201,930.28
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 108,863.43	\$ -	\$ 108,863.43
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (3,455.53)	\$ 2,000.80	\$ (1,454.73)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 188,387.40	\$ -	\$ 188,387.40
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (137,081.14)	\$ 25,277.07	\$ (111,804.07)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (285,958.32)	\$ 7,198.90	\$ (278,759.42)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 657,602.16	\$ (6,994.42)	\$ 650,607.74
19	Real-Time Market Administration Amount	\$ 42,962.14	\$ (3,965.92)	\$ 38,996.22
29	Financial Transmission Rights Market Administration Amount	\$ 62,017.36	\$ -	\$ 62,017.36
33	Day-Ahead Schedule 24 Allocation Amount	\$ 92,692.00	\$ (992.34)	\$ 91,699.66
34	Real-Time Schedule 24 Allocation Amount	\$ 6,084.53	\$ (578.19)	\$ 5,506.34
35	Schedule 24 Admin Allocation	\$ -	\$ -	\$ -
Virtual Energy Charges				
12	Day-Ahead Virtual Energy Amount	\$ -	\$ -	\$ -
27	Real-Time Virtual Energy Amount	\$ -	\$ -	\$ -
Other MISO Charges				
20	Real-Time Miscellaneous Amount	\$ (0.03)	\$ -	\$ (0.03)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 3,093,921.02	\$ -	\$ 3,093,921.02
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (2,850,133.13)	\$ -	\$ (2,850,133.13)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (314,363.01)	\$ -	\$ (314,363.01)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 72,722.46	\$ -	\$ 72,722.46
TOTAL MISO CHARGES		\$ 14,057,577.60	\$ 2,360,910.32	\$ 16,418,487.92
SCHEDULE 24 (FOR RETAIL)				\$ 97,206.00
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 16,321,281.92

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
December 2011 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (123,072.00)	\$ -	\$ (123,072.00)
2	Day-Ahead Spinning Reserve Amount	\$ (42,512.38)	\$ -	\$ (42,512.38)
3	Day-Ahead Supplemental Reserve	\$ (82,613.55)	\$ -	\$ (82,613.55)
4	Real-Time Regulation Amount	\$ (26,568.83)	\$ 52,415.79	\$ 25,846.96
5	Real-Time Spinning Reserve Amount	\$ (18,000.40)	\$ 27,960.24	\$ 9,959.84
6	Real-Time Supplemental Reserve Amount.	\$ 2,018.80	\$ 25,658.77	\$ 27,677.57
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (1,068.25)	\$ -	\$ (1,068.25)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 1,364,756.02	\$ -	\$ 1,364,756.02
8b	Real Time Non Excessive Energy Congestion	\$ 181,854.50	\$ -	\$ 181,854.50
8c	Real Time Non Excessive Energy Loss	\$ 77,021.00	\$ -	\$ 77,021.00
9	Real Time Net Regulation Adjustment Amount	\$ (12,761.14)	\$ 872.28	\$ (11,888.86)
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 208,557.72	\$ -	\$ 208,557.72
11	Real Time Spinning Reserve Cost Distribution	\$ 90,989.01	\$ -	\$ 90,989.01
12	Real Time Supplemental Reserve Cost Distribution	\$ 61,578.93	\$ -	\$ 61,578.93
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 8,407.80	\$ (421.54)	\$ 7,986.26
14	Real Time Contignecy Reserve Deployment Failure	\$ -	\$ (2.14)	\$ (2.14)
TOTAL MISO ASM CHARGES		\$ 1,688,587.23	\$ 106,483.40	\$ 1,795,070.63

